5

EXCHANGE, SCHEDULING AND CONTROL SYSTEM
FOR ELECTRICAL POWER

10

Field Of The Invention

The present invention relates to the field of electrical power generation and _delivery_ ~~distribution~~ systems.

15 Background Information

The electrical power industry in the United States and other countries is characterized by a network of regional power pooling arrangements among various power generators and users. In a typical pooling arrangement, several pool

20 participants contribute generation and transmission resources to form a regional power generation and _delivery_ ~~distribution~~ system. Typically, one organization, which may be co-owned or be a joint venture of the pool participants, is responsible for operating the regional

25 power generation and distribution system. Such an organization may also be referred to as an Independent System Operator (ISO).

One ISO has proposed an energy market which comprises a multi-settlement system and a fixed transmission rights

30 (FTR) auction system. (See "Operating Agreement of PJM Interconnection, L.L.C.," December 31, 1997). This proposal calls for a "two-settlement" system and a Fixed

[NYC] 300418.1

Transmission Right (FTR) auction system. The two-settlement system is to perform scheduling and price calculations for a day-ahead and a real-time market for energy. The FTR auction system is to manage the auction of

5   FTRs. An FTR provides its owner with the right to transfer a specific amount of power over a transmission path for a specific price, regardless of congestion charges that might otherwise apply.

The provisioning of resources in a deregulated,
10   market-oriented power generation and delivery system is a complex, multi-dimensional problem which must be solved repeatedly and accurately to ensure the efficient and secure operation of the system. This problem is further complicated by the integration therewith of an energy
15   market system such as the aforementioned. Unlike conventional markets, such as securities markets where financial interests are exchanged, the transactions of an energy market, as proposed, are subject to the physical constraints of the underlying energy system. It is unclear
20   how the security and efficiency considerations in the operation of a power system can be reconciled with the dynamics of an open market system.

There is therefore a need for a system that can support a forward market for the provision of energy over a
25   power system while ensuring the efficient and secure operation of the power system.

Summary Of The Invention

The present invention provides an energy market system
30   which operates in conjunction with an existing power system control infrastructure. The energy market system of the present invention allows market participants, who are

2

typically electrical power generators and/or power consumers, to buy and sell electrical power and rights in future power delivery.

An exemplary embodiment of a market system in accordance with the present invention comprises a multi-settlement subsystem and a Fixed Transmission Right (FTR) auction subsystem.

The multi-settlement subsystem (MSS) provides market participants with the ability to participate in one or more forward markets for electric energy. In the exemplary embodiment described, a two-settlement system is provided, with one settlement based on a day-ahead market and another, real-time settlement based on actual system operation and real-time prices. A primary function of the MSS is to develop day-ahead and hour-ahead supply and demand schedules based on bid prices and desired and available quantities and to coordinate these schedules with the requirements of reliable power system operation. In addition, the MSS determines Locational Marginal Prices (LMPs) for the energy network.

The FTR Auction subsystem provides for the purchase and sale of FTRs in a centralized auction. Market participants may submit bids for the purchase of FTRs in the auction. They may also offer FTRs for sale in the auction. The auction system will maximize the revenues from the FTR while maintaining the ability of the transmission system to simultaneously support the awarded FTRs.

Brief Description Of The Drawing

FIG. 1 is a block diagram of an exemplary embodiment of an energy market system in accordance with the present

3

invention in conjunction with exemplary power system control system functions.

FIG. 2 is an exemplary embodiment of a hardware arrangement for an energy market system in accordance with the present invention.

FIG. 3 is an exemplary embodiment of a software platform for a market user interface in an energy market system in accordance with the present invention.

FIG. 4 is a flow chart of an exemplary process for conducting day-ahead energy scheduling in accordance with the present invention.

FIG. 5 is a flow chart of an exemplary case setup function for a fixed transmission rights (FTR) auction system in accordance with the present invention.

FIG. 6 is a flow chart of an exemplary simultaneous feasibility test for an FTR auction system in accordance with the present invention.

Detailed Description

FIG. 1 shows a functional block diagram of an exemplary embodiment of an energy market system 100, in accordance with the present invention, in conjunction with control facilities 10 of an exemplary power generation and delivery system, such as that operated by a power pooling organization or Independent System Operator (ISO). The system 100 comprises a Market User Interface (MUI) 110, a Multi-Settlement Subsystem (MSS) 120, a Fixed Transmission Right (FTR) Auction Subsystem (FTRAS) 160, an applications database (ADB) 150 and an Accounting Database 190.

The MUI 110 acts as gateway between Market Participants 50 and the MSS 120 and FTRAS 160 of the energy

4

market system 100. The MUI 110 is preferably expandable, allowing for the addition of future applications beyond the scheduling and auction applications of the exemplary system shown.

5   The MSS 120 enables one or more forward markets for the purchase and sale of electric energy, with a day-ahead market and a real-time market being provided. The FTRAS 160 enables an auction for the purchase and sale of FTRs. These subsystems will be described in greater detail below.

10   The control facilities 10 of a typical power generation and delivery system comprise well-known functional components, including an Energy Management System (EMS) 15 which provides real-time control of the power system. An application database (ADB) 20 is

15 associated with the EMS 15. The ADB 20 contains information for modeling the power network. Data in the ADB 20 is provided to the ADB 150 in the energy system 100, described more fully below.

The EMS 15 includes several well-known network

20 analysis functions which interact with and provide information that is used by the energy market system 100 of the present invention. A standard network analysis function included in the EMS 15 is a Model Update (MU) function 27 which generates a bus model of the power

25 network based on a detailed network model and network configuration information (e.g., switch positions). Network topology, the normal status of logical devices and transformer and phase-shifter tap positions, are available from the ADB 20. The logical device status changes

30 associated with a scheduled outage are available from a list of scheduled outages in an Outage Scheduler (OS) function 24.

The bus model generated by the MU function 27 is used by other functions such as a Dispatcher Power Flow (DPF) function 28, a Security Analysis (SA) function 23, and a Security Constrained Dynamic Optimal Power Flow (SCDOPF)

5   procedure, described below. The MU function 27 also includes standard subfunctions such as bus model updating, load scheduling, interchange scheduling, generation scheduling and regulating equipment scheduling.

A Network Parameter Adaptation (NPA) function 22 in

10 the EMS 15 maintains scheduled values (e.g., by hour), such as interchange values and various setpoints and tap settings for regulating equipment.

A Dispatcher Power Flow (DPF) 28 function of the EMS 15 provides the Dispatcher/Operator mode of an Optimal

15 Power Flow (OPF) procedure (described below). The DPF produces a solution of the power flow problem for a given set of network conditions. This solution satisfies the bus power-balance equations (static load flow equations) for given values of generation, load, and net interchange. The

20 DPF 28 solves the power flow problem without optimization.

Other functions of the EMS 15 include a State Estimator (SE) 25, a Network Sensitivity (NS) function 21, a system load forecast (SLF) function 26 and various functions for transferring data between the EMS functions

25 and the energy market system 100.

The power system control facilities 10 typically include an OASIS (Open Access Same-time Information System) subsystem 11 which provides an on-line interface (e.g., over the Internet) to the market participants 50 for

30 requesting and scheduling transmission service. An ATC (available transfer capability) function 12 provides information regarding the power network's available

6

transmission capacity to OASIS 11 for posting to the market participants. An ACES (accounting, contracts and energy scheduling) function 13 is provided for scheduling exchanges of energy between various utilities. A real-time

5   locational marginal price (LMP) calculation function 16 is included for determining LMPs during actual system operation. An accounting and billing function 17 is also included. As with the EMS 15, the aforementioned functions and their implementations are well-known.

10   FIG. 2 shows an exemplary hardware platform configuration for the system of FIG. 1. The exemplary configuration of FIG. 2 includes redundancy to ensure reliable and continuous operation, although as can be understood, it can also be implemented without redundancy,

15   depending upon the requirements of the application.

      The configuration of FIG. 2 comprises redundant database/application servers 210 and 211 for carrying out the functions of the Multi-Settlement Subsystem 120 and the FTR Auction Subsystem 160. The servers 210, 211 can be

20   implemented, for example, using 64-bit IBM RS/6000 S70 computers, each configured with 12 CPUs. Mass storage for the database/application servers 210, 211 can be provided, for example, by a RAID 1/SSA disk array 220. The databases 120, 150 and 160, for instance, would be maintained on the

25   disk array 220 by the servers 210, 211. A terminal 230 with ASCII display and keyboard provides a user interface to the servers 210, 211 for system administration and operation functions.

      In the exemplary configuration of FIG. 2, redundant

30   servers 240, 241 are used to carry out the functions of the MUI 110. A pair of IBM RS/6000 F50 workstations configured with 2 CPUs each can be used as the servers 240, 241. As

<div align="center">7</div>

with the database/application servers 210, 211, a RAID 1/SSA disk array 250 and a terminal 260 with ASCII display and keyboard are shared by the MUI servers 240, 241.

The server pairs 210, 211 and 240, 241 are configured on dual redundant LANs 270 and 280, respectively. The LANs 270 and 280 can be implemented as 10 and/or 100 Mbs Ethernet LANs. The LANs 270 and 280 are coupled via redundant routers/firewalls 275 and 285. The routers/firewalls 275, 285 isolate the database/application servers 210, 211 from the market participants as required. Such routers/firewalls are available from Cisco Corporation.

In the exemplary configuration of FIG. 2, market participants can access the system 100 over the Internet. The redundant LAN 280, to which the MUI servers 240, 241 are coupled, is coupled to the Internet via an Internet Service Provider (ISP) via a redundant pair of router/firewalls 295, 296. The database/application servers 210, 211 are further isolated from the MUI servers through the router/firewalls 275, 285.

The exemplary configuration of FIG. 2 provides the compute power and reliability to ensure the timely execution of the multi-settlement process. As can be understood, however, other configurations are possible within the scope of the present invention.

The system 100 of FIG. 1 is implemented on a software platform which is implemented on the exemplary hardware platform of FIG. 2. An exemplary embodiment of a software platform includes the AIX operating system at level 4.3 with High Availability Clustered Multi Processor (HACMP) technology that automatically detects system failures and recovers users, applications and data on the backup. In

8

addition, the tools to support the market participant interfaces and the database related activities can be provided by Oracle 8 Server, Oracle Web Server, Oracle Parallel Server, Oracle Developer/2000 Server and Oracle

5 Developer/2000. The network application database related tasks can be handled using Siemens' high performance ADB.

The system 100 includes several databases, such as a scheduling database 130, an FTR auction database 170, the accounting database 190 and the application database (ADB)

10 150. The public data in the databases 130, 170 and 190 and all of the private data not required for network applications execution can preferably be stored and maintained in a general purpose Oracle database. The data required for execution of network applications (e.g.,

15 network model data) is stored and maintained in the application database (ADB) 150. The ADB 150 contains data similar to that in the ADB 20 associated with the EMS 15. The databases preferably support hot backup without taking the applications or database servers offline.

20 A set of APIs supports data exchange internally, inside the system 100 and externally with other systems and the MUI.

FIG. 3 is a block diagram showing the various software components involved in the interface between market

25 participants and the energy system 100. In the exemplary embodiment of FIG. 3, the redundant MUI servers 240, 241 run a HyperText Transfer Protocol (HTTP) Internet Server 351, such as the Oracle Web Server, which interfaces with the application-specific databases 130, 170 to return

30 dynamic web pages to the Market Participant 310. Home pages 361 provide information about the energy market and other relevant user information. An Oracle Developer/2000

9

Server Cartridge 355 is also installed with the Oracle Web Server 351 in order to provide Oracle Web enabled Forms capability. The use of the Oracle Forms product is extended through the use of the web enabled forms

5   capability.

Internal users can access the energy market system for administrative (e.g., maintenance and development) purposes over the LAN 270 in a client-server configuration with user interface (UI) clients and the database/application servers

10   210, 211. The UI clients can run, for example, Oracle Forms and/or the Siemens ADV tool with X emulation on NT Workstations (Exceed or similar tool). For Market Participants, Oracle Web-enabled forms and templates can be used for the upload and/or download of data.

15   Market Participants can access the energy market system 100 via the Internet by using a web browser 310, such as Netscape Navigator or Microsoft Internet Explorer. For security, Secure Sockets Layer (SSL), 128 bit encryption, server-side certificates and client-side

20   certificates are also preferably supported.

When the HTTP Web Server 351 receives a Uniform Resource Locator (URL) from a browser 310 located on the World Wide Web (or on a local network using HTTP), the Web Server 351 draws on information from the database 130, 170

25   and the operating system's file system, as necessary, to respond to the request. The file system can be used for static Web pages and the database can be used for Web pages that are generated at runtime using "live" data.

The Forms component of Developer/2000 for the Web

30   consists of two components: the Forms Client and the Forms Server. The Oracle Developer/2000 Server is installed in a MUI server 240, 241 as a WRB cartridge 355.

<div align="center">10</div>

The Forms Client is a Java applet 311 which is downloaded at runtime to an end user's Web browser and displays the form's user interface and manages interaction between end users and the Forms Server. The Forms Client 311 receives "bundles" of interface commands from the Forms Server and translates them (in sets) into interface objects for the end user

The Forms Server includes a listener and a runtime engine. The listener initiates the Forms runtime session and establishes a connection between the Forms Client and the Forms Server Runtime Engine. The runtime engine handles all form functionality except UI interaction, including trigger and commit processing, record management, and general database interaction. The Forms Server Runtime Engine (and all application logic) is installed on the MUI (240, 241) and the database/application servers (210, 211), not on client machines. All trigger processing occurs on the application database and MUI servers, while user interface processing occurs on the Forms Client. Further information regarding this exemplary arrangement is available from Oracle Corporation. As can be understood other arrangements are possible within the scope of the present invention.

As can be understood in light of the present disclosure, the specific displays and presentation of information at each market participant are designed in accordance with the business rules surrounding a Market Participant login session including specific rules for data integrity, reasonability, confidentiality and availability. Furthermore, upload/download templates are provided for the transferal of Market Participant information.

11

Exemplary hardware and software platforms for the energy market system 100 of the present invention have thus far been described. The two exemplary applications or subsystems of the energy market system 100 will now be
5 described in greater detail, beginning with the multi-settlement subsystem 120.

MULTI-SETTLEMENT SUBSYSTEM

10

The multi-settlement subsystem (MSS) 120 provides the market participants 50 with the ability to participate in a forward market for electric energy. In the exemplary embodiment described, there is a day-ahead market and a
15 real-time market. A primary function of the MSS 120 is to develop day-ahead and hour-ahead supply and demand schedules based on bid prices and quantities and to coordinate these schedules with the requirements of reliable power system operation. In addition, the MSS 120
20 determines Locational Marginal Prices (LMPs) for the energy network.

FIG. 4 is a flow chart showing an exemplary process performed by the MSS 120 in providing day-ahead scheduling and LMP calculation. A purpose of the day-ahead scheduling
25 and LMP calculation process of FIG. 4 is to evaluate bids submitted by market participants 50, more specifically, generators and load serving entities (LSEs) for the day-ahead energy market with the objective of devising an economical commitment and dispatch of generation with
30 associated LMPs.

The commitment and dispatch of generation resources in accordance with the exemplary process of FIG. 4 is

12

characterized by a plurality of features and capabilities, including one or more of the following:

- handling generator bids which contain start-up, no-load, and energy prices, start-up time and ramping constraints, minimum run time, and minimum off time until next start-up;

- respecting limits on the maximum number of starts per day or per week for each of a plurality of generating units;

- modeling transmission losses, fixed generation, fixed demand, dispatchable generation and demand, and fixed bilateral transactions;

- modeling transaction curtailment;

- modeling increment and decrement bids associated with transactions;

- market power mitigation using generator price caps in the event of transmission congestion;

- handling limited energy units with maximum up time constraints;

- least-cost commitment and scheduling of generation to meet the market forecast load (sum of load bids) taking into account reserve requirements and n-1 security requirements;

- commitment and scheduling of additional resources to cover the difference between forecasted generating and forecasted load based on minimization of start-up and no-load cost, taking into account reserve requirements and n-1 security requirements;

- respecting security criteria considering a full transmission system model that accommodates reactive interface limits and single-contingency

13

thermal limits respecting all contingencies
monitored in the current EMS system; and

    o   fully-automated daily schedule production
with fast execution time (e.g., less than 40

5   minutes).

    In executing the process of FIG. 4, day-ahead hourly
cases are first set-up in the Scheduling Database 130 at
step 401. Step 401 is preferably carried out as an

10   automated procedure in order to satisfy the time
constraints of the day-ahead scheduling process. The setup
procedure in step 401 takes the information entered by the
Market Participants, and information produced by the EMS
functions and other sources (e.g., maintenance plans,

15   weather forecasts), processes this raw data and produces 24
hourly sets of data that can be used by the various
procedures and functions involved in the operation of the
MSS 120.

    An exemplary list of data that is setup in the

20   scheduling database 130 includes:

    o   market entered information about generation and
       load bids;

    o   full breaker-oriented model of the transmission

25   network;

    o   penalty factors from the EMS NS function 21;

    o   scheduled values from the EMS NPA function 22;

    o   current real-time contingency list from the EMS
       SA function 23;

30   o   relevant outage information from the EMS OS
       function 24;

14

- the latest EMS SE 25 solution

- load forecast results from the EMS SLF function 26;

- the status (from the EMS) of generation equipment with long start-up requirements for the first hour of the operating day;

- transmission reliability limits;

- transfer interface limits;

- branch ratings;

- fixed generation and load as well as bilateral transactions;

- definition of price aggregation zones;

- input data for transaction curtailment in the case of congestion;

- input data for market power mitigation using generator price caps; and

- end conditions from previous unit commitment run.

Once the scheduling database 130 has been set-up in step 401, execution proceeds to step 403 in which a unit commitment (UC) procedure is carried out.

An exemplary UC procedure in accordance with the present invention operates on a multiple-day horizon (e.g., 5, 7 days) in order to take into account the effect of the end conditions of the one-day scheduling horizon. In other words, the UC procedure compensates for the possible myopia of the short (24 hours) scheduling period. This avoids the problem, for example, of shutting down some units at the end of one day even though the capacity may be needed the next day.

15

The UC procedure executed at step 403 is price-based; i.e., it produces the most economical commitment of generation over the next day which meets the market forecasted load and appropriate network reserve requirements. In this UC procedure, a subset of major transmission line limits is directly modeled and enforced. This subset contains the transmission lines that are known to have been run against the limits in the recent past (and as such may likely be overloaded again). Any other useful criteria from past experience may also be used to identify such a subset. An exemplary UC procedure in accordance with the present invention will be described below in greater detail.

The execution of the UC procedure at step 403 yields a schedule which is then evaluated in light of "n-1 security" criteria in the next series of steps (steps 405, 407, 409 and 411).

At step 405, a Security Analysis (SA) procedure is carried out. The SA procedure of step 405 is similar in functionality to the SA function of the EMS 15 but is executed, independently, by the MSS 120. The SA procedure of the MSS simulates one or more contingency cases (e.g., performs an AC analysis) and identifies all violations resulting from the simulation. The contingency cases are provided in a contingency list which is typically prepared by the ISO and maintained by the EMS 15. The SA procedure also produces corresponding linearized functional constraints (e.g., branch flow constraints) and adjusted control variable limits which are passed to the SCDOPF procedure, described below. The SA procedure is executed for each hour, preferably in parallel for each hour separately using the parallel CPU architecture of the

16

database/application servers 210, 211. An exemplary SA procedure is described in further detail below.

Once each contingency in the contingency list has been simulated by the SA function, it is determined at step 407 whether there would be any violations if the system were to operate under any one of the contingencies. If it is determined at step 407 that there would be violations, execution proceeds to step 409 in which a Security Constrained Dynamic Optimal Power Flow (SCDOPF) procedure is carried out. The SCDOPF procedure determines the optimal dispatch of generation in light of the linearized functional constraints prepared by the latest SA run (at step 405), the upper and lower limits on control variables, reserve constraints, and ramping constraints. An exemplary embodiment of a SCDOPF procedure is described in greater detail below. The SA and SCDOPF procedures operate in a closed loop, executing iteratively, to converge on a solution.

There are two possible outcomes of the execution of the SA-SCDOPF loop (steps 405-409). One possibility is that the overall process converges and it is determined at step 407 that there would be no violations for any contingency listed in the contingency list. In this case, execution proceeds to step 413 in which the calculation of LMPs is performed.

If it is determined at step 411 that the SA-SCDOPF loop cannot produce a feasible solution, it means that n-1 security cannot be met with the existing commitment. In that case, the set of constraints that cannot be satisfied (the "critical constraints"), as determined by the last execution of the SCDOPF procedure, is provided to the UC procedure (step 403). The UC procedure is run again (at

17

step 403) with an expanded list of transmission
constraints. As a result, the UC procedure produces a new
commitment which takes into account the new critical
constraints. The SA-SCDOPF loop (steps 405-409) is

5   executed again until it converges on a violation-free
solution, as determined at step 407. As described above,
execution then proceeds to step 413 in which the LMPs are
calculated. An exemplary procedure for calculating LMPs is
described more fully below.

10   After the LMPs have been calculated in step 413,
execution proceeds to step 415 in which it is determined if
any transactions are to be curtailed because one or more of
the parties to the transactions are not willing to pay
congestion charges. Congestion charges apply when the LMP

15   at a delivery point is greater than the LMP at the point of
generation. Whether congestion charges will apply to a
particular transaction is thus determined when the LMPs are
calculated, at step 413, in accordance with the schedules
produced by the UC/SA/SCDOPF solution generated in steps

20   403-411. The congestion charges thus determined may for
some transactions exceed the maximum congestion charges the
parties to those transactions are willing to pay. If so,
those transactions are to be curtailed, as determined in
step 415. As mentioned above, curtailment information

25   (e.g., when, how and/or how much to curtail) is loaded into
the scheduling database 130 at step 401. If there are
multiple transactions to be curtailed, additional
curtailment criteria can be applied to determine which
transactions to curtail, in which order, to which extent,

30   etc. Such criteria may include whether or not a
transaction considered for curtailment might otherwise
contribute to a congestion condition. At step 417, the

18

transactions selected for curtailment are curtailed
accordingly and execution loops back to repeat the
UC/SA/SCDOPF/LMP processing steps 403-413, giving effect to
the curtailments.

5   After transaction curtailment and re-execution of the
UC/SA/SCDOPF/LMP procedures, execution proceeds to step 419
in which it is determined whether there are any generator
price caps that come into effect (as specified in data
loaded at step 401 into the scheduling database 130). If
10   price capping is to be performed for some generation units,
execution proceeds to step 421, in which the price caps are
put into effect, and then loops back to repeat the
UC/SA/SCDOPF/LMP procedures with modified price bids for
those generation units to which price capping applies.

15   Once the UC/SA/SCDOPF/LMP processing has been repeated
taking into account the price caps, execution proceeds to
step 423 in which it is determined whether the optimal
schedules thus produced meet predetermined reliability
criteria (e.g., reserve capacity, number or severity of
20   violations under certain contingencies, the difference
between scheduled generation capacity and forecasted load).
Such criteria are typically specified by the ISO. In
making this determination, the total forecasted load for
the period (as forecasted, for example, by the energy
25   system operator) plus appropriate reserve requirements is
compared to the amount of load bids plus an appropriate
reserve. If the difference is below a predefined
tolerance, the day-ahead scheduling and LMP calculation
process is deemed complete and execution proceeds to step
30   425 in which the final schedules and LMPs are written to
the scheduling database 130.

19

If, however, it is determined at step 423 that the difference between the forecasted load and demand bids does not meet the predetermined reliability criteria, it is necessary to commit additional generator resources to cover this difference. The additional resources include available units that were not committed in the UC procedure of step 403. These resources are dedicated for providing spinning reserve service and include mostly gas turbines and other fast starting units and units that can run with little or no load ("no-load" units). Commitment of these units is carried out in step 427 by a Marginal Unit Commitment (MUC) procedure.

The MUC procedure is a special application of the UC procedure of step 403. The MUC procedure includes the features of the UC procedure except the modeling of transmission constraints. The MUC procedure is also used for supplemental unit commitment runs during hour-ahead scheduling in the case of forced outages or unusual load forecast error, as described more fully below in connection with hour-ahead scheduling. Usually, the MUC procedure commits, as spinning reserve, only no-load generation units. It is possible however that some of the reserve units committed at step 427 have positive minimum loads. In order to use such units for providing reserve power, it is necessary to operate those units at their minimum loads. If it is determined at step 429 that the sum of the minimum loads of the reserve units committed by the MUC procedure in step 427 is zero, the day-ahead scheduling and LMP calculation process is deemed complete and the final schedules and LMPs are written at step 425 to the scheduling database 130. If, however, any of the committed reserve units (for instance, a steam generator) has a

20

minimum load greater than 0, execution loops back to step
403 so that the day-ahead scheduling and LMP calculation
process is repeated starting from the UC procedure. The UC
procedure is re-run taking into account the reserve
generation units committed by the MUC procedure in step
427.

    If the total minimum power of all units committed by
the UC and MUC procedures at steps 403 and 427 is less than
the market forecasted load for any hour of the day in
question, the UC run at step 403 will be skipped. In this
case, 24 hour closed loop SA-SCDOPF execution is performed
in order to find the optimal dispatch, while considering
the minimum power limits of the units committed in step 427
and satisfying n-1 security.

    If there is over-generation, i.e., if the total
minimum power of all units committed in steps 403 and 427
is greater than the market forecasted load for any of the
24 hours, the difference between the total minimum power
and the total load is calculated by the MUC procedure and
the UC procedure of step 403 is repeated. The purpose of
this run is to find a commitment solution which eliminates
the over-generation either by re-committing units committed
by the MUC procedure, modeling units committed in the UC
procedure as "must run" units, or as a last possibility,
re-committing all units committed by both the UC and MUC
procedures.

    The various functions involved in the scheduling
process of FIG. 4 will now be described in greater detail.

SECURITY ANALYSIS

21

The Security Analysis (SA) procedure analyzes system security under contingency conditions. The procedure operates upon a solved power flow network called the base case. The base case corresponds to one of the 24 hours

5   being analyzed and includes the latest generation schedule as determined by the last execution of the Unit Commitment (UC) procedure.

The SA procedure performs several functions which will now be described.

10   A function of the SA procedure is to simulate contingencies and analyze system security under each contingency specified in a contingency list provided by the EMS 15. The contingency list can include one or any combination of the following equipment changes:

15

● branch element outages (lines, transformers, phase-shifters, series devices);

● generator unit outages;

● Static Var Compensator (SVC) outages;

20   ● load element outages;

● shunt capacitor/reactor outages; and

● switching device changes.

A piece of equipment can be placed in service by explicitly defining all of the switching device changes

25   required to place the piece of equipment into service.

Any line or transformer can be identified in the ADB database as potentially causing a topology change when it is outaged. When a contingency includes the outage of one

22

of these branches, the contingency will be analyzed for the possibility of a topology change and the solution obtained will use a new model containing the new topology, if required.

5   A Contingency Editor is used to maintain the contingency list. The contingency list that exists in the EMS's real-time SA function may also be retrieved on request.

Contingencies can be organized into groups. Operator-
10   settable flags can be used to include/exclude each contingency from each of the contingency groups. Another set of operator-settable flags activate/deactivate each of the contingency groups. Any contingency which is enabled in at least one active group is evaluated by the SA
15   procedure.

The SA procedure employs a contingency screening function to rank the contingencies specified in the Contingency List. This ranking is done according to the calculated severity of the resulting branch real power
20   overloads and/or the calculated severity of the resulting voltage and reactive power limit violations. In the screening phase, network voltages and flows are estimated by a relatively small number of iterations of a Fast Decoupled Power Flow (FDPF) function. Implementations of
25   such a function are well known. The number of iterations can be user-specified. Selected contingencies are later solved by a full FDPF. Quantities that are to be monitored for limit violations can be specified by a system operator in a Violation Check List.

30   The contingency screening function processes the contingencies that are enabled in one or more of the active contingency groups. The screening function sorts all

23

contingencies into two separate Screened Contingency Lists:
1) a Real Power Screened Contingency List, in which
contingencies are sorted according to the expected severity
of branch real power overloads; and 2) a Voltage/Reactive
Power Screened Contingency List, in which contingencies are
sorted according to the expected severity of bus voltage
limit violations or bus reactive power limit violations.

A user may select either or both Screened Contingency
Lists for full simulation. Contingencies in the Screened
Contingency Lists are simulated until a "Stopping
Criterion" is met. Stopping Criteria may take one of the
two forms: "Simulate the top N cases in the list" (the "N"
criterion) or "Simulate all cases with possible
violations." (the "ALL" criterion). Contingencies which
are flagged as "must run" are automatically selected for
full simulation. As some contingency cases may be in both
screened lists, the lists will be merged and redundant
entries eliminated before full analysis takes place.

If the "ALL" criterion is selected, then after the.
desired number of screening iteration(s) of the FDPF for
each contingency, the solution is checked for possible
violations. If a violation is detected, the solution
process directly continues with a full AC analysis until a
converged solution is obtained. This solution is then
checked again for violations. If there is no violation
after the screening iteration(s), the full solution is not
required or performed. If the "ALL" stopping criterion is
selected, no performance indices are computed and no
screened contingency rankings are performed

If the "N" criterion is selected, then all
contingencies are screened first. Ranking is performed
based on the performance Indices which are calculated after

24

the screening iterations. The performance index of a
contingency is indicative of the severity of the
contingency. During screening, two rankings are produced,
one based on the "worst individual violation" and the other

5   based on overall severity. The user may preselect the
ranking criteria to be used. Contingencies for which no
violation is detected have a performance index value equal
to zero and thus no ranking is done for these cases. The
top "N" cases from both the Real Power Screened Contingency

10 List and the Voltage/Reactive Power Screened Contingency
List are selected for full analysis.

The contingency ranking for screening is only
performed when the "N" stopping criterion is selected.
Only the contingencies that have violations during the

15 screening are ranked. However, a user-specified global
screening threshold percentage is available. This
screening threshold percentage is multiplied by each of the
violation thresholds and is used only during screening. By
setting this threshold to some very small percentage, the

20 screening function of the SA procedure is forced to
calculate a performance index for each contingency. The
user also has the option of setting the threshold to 100%,
in which case, only the contingencies with violations
during screening will have a performance index calculated.

25 Selected contingencies are then solved by a full FDPF.
For both screening options ("N" or "ALL"), generation and
ranking of the violation output are based on the results of
the full FDPF analysis.

The exemplary SA procedure of the present invention

30 can simulate and solve contingencies that result in
islanded systems and isolated buses. For every island, a
new slack bus is assigned and all islands are solved

25

simultaneously. Furthermore, the solution of the SA procedure can be obtained with or without generator MVAR limits enforced. This option is user-selectable.

For each contingency simulated, specified elements are

5 checked for limit violations (e.g., line overloads). All contingencies which cause violations are listed along with the identification and magnitude of the violations. The base case is automatically checked for violations.

Any branch which has a violation under one or more

10 contingencies is classified to be in either trend mode or contingency mode. The SA procedure will flag a branch as being in contingency mode if the maximum flow on the branch that results from any of the contingencies being evaluated exceeds the branch's long-time emergency limit. The SA

15 procedure will flag a branch as being in trend mode if the maximum flow on the branch that results from any of the contingencies being evaluated is between its normal limit and its long-time emergency limits (or short-time emergency or load dump if selected).

20 Any monitored bus voltage which has a violation under one or more contingencies is classified to be in either trend mode or contingency mode. Three separate voltage trend displays are provided on the operator terminal 230: Voltage Drop Trend, Low Voltage Trend, and High Voltage

25 Trend. For Voltage Drop, the SA procedure will flag a bus voltage as being in trend mode if the voltage drop exceeds a Voltage Drop Warning Limit but not a Voltage Drop Limit. For Low Voltage, the SA procedure will flag a bus voltage as being in trend mode if the post-contingency voltage at

30 the respective bus is below a Normal Low Limit (user-specified) but not an Emergency Low Limit (also user-specified). For High Voltage, the SA procedure will flag a

26

bus voltage as being in trend mode if the post-contingency voltage at the respective bus is above a Normal High Limit but not an Emergency High Limit. Bus voltage trends may appear on one, two, or all three of the voltage trend

5   displays. Any bus voltage which is in contingency mode, i.e., exceeds the Voltage Drop Limit, Emergency Low limit, or Emergency High limit for one or more contingencies, will not appear on the respective Voltage Trend display. The aforementioned limits are user-specifiable.

10   The contingencies simulated by a full solution are ranked separately for thermal overloads and voltage/reactive power violations. This ranking information can be displayed along with the contingency list. The ranking can be used as a guide in the process of

15   establishing the active contingencies for each of the groups, and also in selecting a stopping criterion for the contingency screening process.

Severity ranking calculates each contingency's performance indices after a full FDPF solution, while

20   contingency screening calculates each contingency's performance indices after the screening iterations. The contingency screening calculates active power performance and voltage/reactive power performance indices, while the severity ranking calculates a performance index for each of

25   the following categories of contingency violations or base case deviations:

    ◦ branch flow Normal (or, if selected by the user, Long Time Emergency) limit violations;

30   ◦ bus voltage Normal (or, if selected by the user, Long Time Emergency) limit violations;

27

o reactive power generation limit violations;

o bus voltage shifts from base case; and

o reactive power generation shift from the base case.

5   For ranking purposes, two severity indexes are calculated, one to be used for Contingency Screening, and one for organizing Full Contingency Analysis output in order of severity. Both rankings are based on a weighted sum of contingency violations and base case deviations,

10   where different weights can be defined for each of the two severity indexes. Weights may be assigned to a whole category (e.g., bus voltage limit violations) or for individual violations or base case deviations.

       Any branch, the reactive component of any generator,

15   and any voltage level within a station may be included in the Violation Check List. Each of these elements (branches, generators, and voltage levels) has an operator-specifiable priority associated with it. The user may select, for each execution of the SA procedure, the

20   priority range to be used for selecting the elements to be in the Violation Check List (e.g., all elements in priority range 2-4). All branches, generators, and voltage levels within the specified range are included in the Violation Check List and are checked for violations.

25   A user can specify the percentage of the ratings at which a violation message is to be generated for branch flow limit violations, bus voltage limit violations, bus voltage drop violations, generator MVAR overloads, and generator MVAR shift violations. For example, an 80

30   percent branch flow normal limit violation would result in

28

a violation message whenever a branch is loaded to more than 80 percent of its normal limit.

The Violation Check List can include checks for:

5
- branch flow Normal limit violations;

- branch flow Long-Term Emergency limit violations;

- branch flow Short-Term Emergency limit violations;

- branch flow Load Dump limit violations;

10
- bus voltage limit violations;

- bus voltage drops from base case; and

- reactive power generation limit violations

If the contingency consists of a generator unit or load outage, the lost generation (or load) is distributed
15 among the rest of the generators in the system by a Generator Allocator subfunction using participation factors. Two sets of participation factors exist: Long Term and Short Term participation factors. The Long Term participation factors represent the effects of an economic
20 re-dispatch of power. The use of Long Term or Short Term participation factors is user-selectable on an individual contingency basis. The Generator Allocator participation factors are pre-specified and can be user modified. Unit MW limits and islanding are respected by the Generator
25 Allocator subfunction. If the loss of generation and/or load cannot be made up by the other units in an island, an error message is issued stating that an island cannot be solved.

An individual branch or bus can be associated with a
30 set of equipment changes called cascading equipment

outages. If a branch's flow or a bus voltage is violated during a contingency simulation, the associated equipment changes are added to the contingency equipment changes and the contingency is re-simulated. Valid cascading equipment

5 outages include branch outages, capacitor/reactor outages, generator outages, load element outages; and switching device operations (open or close).

Another subfunction of the SA procedure deals with load changeover operations, which are associated with

10 specific line or transformer equipment outages. A load changeover operation is defined by specifying the source node(s) of the load to be moved, the receiving load node(s), and the percentage of the source load the receiving node(s) load should be increased by. Any lost MW

15 load after the changeover is subtracted from the system generation and the Generator Allocator subfunction, described above, is called to reach a power balance.

Changes in the status of logical devices (e.g., breakers, switches) can cause topology changes within a

20 station. Should this occur, the network representation internal to the SA process is modified accordingly during the simulation of the contingency.

A possible outcome of opening a logical device is a bus split. In order to detect a bus split, the SA

25 procedure examines the substation topology on a breaker level and decides if any new buses are created. If any of these new buses are isolated, then all equipment connected to such new buses will be removed during the simulation of the contingency causing the bus split. If any new non-

30 isolated buses are created due to bus splitting, then the network representation internal to the SA procedure is modified accordingly during the simulation of the

30

contingency. If a bus connected to a generator (or load) is split by the contingency, the SA procedure associates the generator (or load) with the bus that contains the node that the generator (or load) is connected to in the network

5   model.

If the closing of a logical device merges two buses within a station, a station topology rebuild is performed. Closing a logical device can reconnect a generator or load that was dead in the base case. However, this generator or

10   load has no injection capability and the MW and MVAR injection are set to zero.

The SA procedure in accordance with the present invention also has the capability to analyze voltage control. The equipment that performs voltage regulation

15   control includes generating units, LTC transformers, Static Var Compensators (SVCs); and Voltage Control Capacitors and Reactors. Voltage Control is performed within the limits of the regulating device using the base case capability curves. MVAR limits are respected for generating units,

20   static var compensators, and voltage controlled capacitors/reactors. Transformer tap position limits are respected during LTC transformer voltage control. The setpoint voltage is defined as the solved base case voltage for the terminal bus.

25   A system operator can enable/disable generator, SVC MVAR limiting, voltage controlled capacitor/reactor switching, and LTC transformer tap changing. Each type of control may be enabled or disabled on a global basis, on a company basis, on a contingency basis, or on an individual

30   equipment basis.

To simulate generator and SVC MVAR limiting, a bus type changing scheme is used. In this scheme, reactive

31

injections at generator buses are checked against their limits. For those buses with violations, the reactive injection is set at the limit value, the bus type is changed to a load bus, matrix factors are updated and the

5   solution process is continued. If, at some later time, the bus can be converted back to a generator bus at the scheduled voltage without any violations, it is converted back to a generator bus.

10

UNIT COMMITMENT

An exemplary embodiment of a Unit Commitment (UC) procedure in accordance with the present invention will now

15   be described. An important aspect of operating a power system is the scheduling of thermal generating units (e.g., combustion, steam, nuclear) and power transactions to supply the load with power at a minimum operating cost. Minimum costs are achieved by determining the most

20   economical start up and shut down times for the thermal units and power transactions, and their associated output power levels.

The study period considered by the UC procedure is divided into intervals (e.g., hour, half-hour), and the

25   unit commitment problem is treated as a discrete-time problem. At every time interval, decisions of starting up and shutting down generating units are made. In an exemplary embodiment, the UC procedure operates with a basic time step of one hour with a study horizon ranging

30   from the basic time step (i.e., 1 hour) to 168 hours (1 week).

32

To assure the determination of realizable schedules, the UC procedure takes into account a variety of operating constraints relating to the generating units, plants and the overall energy system. Furthermore, in order to maintain the security of the transmission system, the UC procedure takes into account transmission flow limits and transmission losses (by means of penalty factors).

In addition to providing generation to meet the load, scheduled units must also provide reserve margins to meet uncertainties of the forecasted load or to cover equipment failure. The provision of these reserve margins and satisfying other constraints entails additional cost.

The UC procedure of the present invention minimizes costs including fuel cost, unit startup cost, unit operating and maintenance cost and power transactions cost.

The UC procedure can operate in real-time mode (i.e., automatically at regular time intervals) or in a study mode. When operating in real-time mode the starting point of the UC study period is the current time, while in study mode, the starting point is user-selectable. The end point is the end of the current or next study horizon or the end of an energy limitation, if applicable.

The UC procedure provides the status (e.g., ON or OFF), as well as the power outputs of thermal units at every time step. The UC procedure also determines the optimal scheduling of interchange transactions.

As discussed, the primary objective of the UC procedure is to determine the startup and shutdown schedule of available generating units as well as the scheduling of power transactions to meet system load and reserve requirements at minimum cost for an entire study period,

33

subject to a variety of equipment, system, and environmental constraints.

Input data to the UC procedure include 1) unit data, 2) unit group data (e.g., plant data), 3) interchange data, and 4) system data. The input data can be data that is constant over the study horizon or data that is variable over the study horizon. Variable data can be specified by a schedule.

The unit data considered by the UC procedure includes unit status, unit type, unit constraints, unit operation curves and unit cost data.

The unit status can be specified for each unit, for each time step. Units can be "available," in which case they may be committed or decommitted, as decided by the UC procedure. Units can be "fixed," in which case they are not considered for optimization purposes. Fixed units are usually nuclear or very large steam units. Units can be "must-run" units, such as those units which must be kept on-line for voltage control purposes. Must-run units must not be decommitted but they may be dispatched to a higher or lower level of generation. Finally, units can be "unavailable." Units whose status is "unavailable" are off-line due to scheduled maintenance or forced outages.

The unit type indicates the type of generation unit, such as nuclear, fossil-fueled steam thermal, multi-fueled, gas turbines, and combined cycle units.

Unit constraints input to the UC procedure include unit generation limits, such as maximum capacity, maximum generation limit, minimum capacity and minimum generation limit. The minimum and the maximum generation limits constrain the operating range. These limits can be changed

34

by a system operator. The maximum capacity is used as the unit's capability for reserve calculations.

Another unit constraint is derated capacity, which can be specified by a schedule. Partial outages of a unit (e.g., a feed mill being out) can limit the unit's maximum output to a value below its full maximum capacity.

Other unit constraints include: minimum up-time (if the unit is turned on-line it must stay on for a certain period of time); minimum down-time (if a unit is shut down it must stay down for a certain period of time); limited ramp rate of unit loading (the maximum allowable change of unit power output between two time steps is limited by the sustained ramp rate, which may be different for load increase and load decrease); reserve contribution limits (as the reserves have to be available within a specified period of time, the contribution of each unit to these reserves can be limited); maximum up-time (if the unit has a limit on energy that can be generated because of fuel or other constraints); and unit dependent conditions (some units can only be started up if a certain unit is already in operation or off-line).

As mentioned, the UC procedure can also use as inputs the operation curves of generating units. The operator can enter the input/output curve, the heat rate, and/or the incremental heat rate curve for each unit. Each unit may be associated with several operation curves to consider different fuels or different cooling agent temperatures. The operator can specify the cost curve of a unit at every time step by assigning an input/output curve and a fuel type to the unit at every time step via schedule displays.

Unit cost data which can be input to the UC procedure can include fuel costs, start-up cost, shut down cost,

35

start up cost when cooling down the unit's boiler (this
cost depends on the time interval between the last shutdown
and start up), operating and maintenance costs and penalty
factors. As mentioned, the UC procedure can also consider
5   unit group constraints. A group of units can be defined
for units which are coupled, for example, by the primary
fuel supply (e.g., gas pipe line or oil tank storage).
Other unit group constraints include plant-related
constraints. For example, crew or auxiliary system
10   limitations may limit the maximum number of units at a
plant which can be started up simultaneously.

The UC procedure can also take into account data for
interchange transactions with a neighboring utility or
pooling arrangement. Such data is provided from an
15   Interchange Transaction Scheduler (ITS) function. For each
utility, several transactions may exist. All transaction-
related data can be modified/entered by the operator via
the ITS function.

Constraints related to interchange transactions
20   include start and stop time, maximum interchange power for
each time interval, minimum interchange power for each time
interval, and maximum/minimum energy over a certain time
period. In addition to constraints, the UC procedure can
also consider cost data related to interchange
25   transactions, including energy price of the transaction,
capacity price of the transaction and penalty factor.

The UC procedure can also consider system-wide
constraints. One such constraint is total system demand.
The total system demand is determined by the SLF function
30   26 or may be specified by the system operator.

Another system-wide constraint is desired spinning
reserve which can be specified in several ways: by a

36

spinning reserve schedule (a fixed MW amount is given for each time interval); as a percentage of forecast load (the total capacity of the committed units at any time interval exceeds the forecast load of that interval by a certain

5   amount); as a percentage of largest unit on-line (the loss of generation of the largest unit on-line can be picked up within a specified time); or by other generation reserve policies to be implemented.

Other system-wide constraints that can be applied as

10   inputs to the UC procedure include: desired standby reserve (the possible data input for the standby reserve requirement is similar to the definition of the desired spinning reserve); required system ramping capability (the on-line units must have the capability to follow strong

15   load variations); and transmission network constraints (imposed minimum/maximum flow limits on certain critical transmission lines at a particular or multiple time periods).

The exemplary UC procedure of the present invention

20   uses an Augmented Lagrangian Relaxation algorithm to provide a unit commitment solution. Other algorithms that can be used include merit order (according to average unit's costs), dynamic programming, the branch and bound method, and Benders decomposition. The objective of the

25   master problem for unit commitment is to minimize the total system cost, TSC, over the entire study period:

$$TSC = \sum_{t}\sum_{i}[F_i(P_{i,t}) + TNC_{i,t}] \qquad\qquad \text{(EQ. 1)}$$

30   Where:

t = Hour of study period

37

i = Generating unit or dispatchable transaction index

Pi,t = Generation of unit i or MW level of
    dispatchable transaction i at hour t

Fi   =   Production Fuel cost of unit i or cost of
5   dispatchable transaction I

TNCi,t = Transition cost that is the sum of start up
          and shut down costs.

The minimization of TSC is subject to the above-
10 described constraints which are taken into account by the
UC procedure, e.g., coupling constraints such as the
generation/load/interchange balance equality constraint,
reserve inequality constraints, transmission transfer
interfaces or lines/transformers flow constraints, etc.
15 These constraints can be represented as follows:

$$\sum_i U_{i,t} \bullet P_{i,t} = D_t \qquad t = 1,...,T \qquad\qquad (\text{EQ. 2})$$

$$\sum_i U_{i,t} \bullet f_{i,m}(P_{i,t}) \geq R_{t,m} \qquad t = 1,...,T; m = 1,...,M \qquad (\text{EQ. 3})$$

20   Where: m = Coupling constraint index

                  M = Number of coupling constraints

                  T = Number of time increments in the study
                       period

                  Ui,t = Operating status of unit i at hour t

25   Dt = System demand requirement at hour t

                  fi,m = Contribution of unit/dispatchable
                          transaction to constraint m

                  Rt,m = Value of constraint requirement m at
                          hour t.

30

38

The above system constraints are relaxed and added to the cost function using Lagrange multipliers. In addition, quadratic penalty terms associated with system demand requirements are added to the objective function to improve the convexity of the problem. The Augmented Lagrangian function, L, can therefore be written as:

$$L = \sum_t \left\{ \sum_i [F_i(P_{i,t}) + TNG_t] - \lambda_t \circ \left[\sum_i U_{i,t} \circ P_{i,t} - D_t \right] \right.$$

$$+ c/2 \circ \left[\sum_i U_{i,t} \circ P_{i,t} - D_t \right]^2$$

$$\left. - \sum_m \mu_{t,m} \circ \left[\sum_i U_{i,t} \circ f_{i,m}(P_{i,t}) - R_{t,m} \right] \right\}$$

(4)

where c is a penalty factor or penalty weight.

The Augmented Lagrangian function L can be initialized based on the difference between the largest and smallest system incremental costs divided by the difference between load values corresponding to the system lambdas

Except for the quadratic term, the Augmented Lagrangian function L is separable and the master problem can be decomposed into a set of independent subproblems each associated with its own local constraints. To overcome the non separability of the quadratic term and maintain the separability of the problem, the Auxiliary Problem Principle is used to linearize the quadratic terms around the current operating point. Thus, the augmented Lagrange function for the subproblems in the (k+1)th iteration is:

39

$$L = \sum_t \{ \sum_i [F_i(P_{i,t}) + TNC_{i,t} - \lambda_t \circ P_{i,t} - \sum_m \mu_{t,m} \circ f_{i,m}(P_{i,t})$$

$$+ c \circ P_{i,t} \circ \left(\sum_j P_{j,t}^k - D_i \right) - \frac{c}{2} \sum_j P_{j,t}^k \circ P_{j,t}^k \qquad (5)$$

$$\frac{1}{2\varepsilon} \left(P_{i,t} - P_{i,t}^k \right)^2] + \lambda_t D_t + \sum_m \mu_{t,m} \circ R_{t,m} \}$$

In the convex case, the algorithm converges when 1/e >
2c. For a given set of Lagrange multipliers, these local

15   optimization subproblems can be solved independently using
a single unit dynamic programming (DP) method. Within the
local optimization subproblems the coupling constraints
have no direct effect; they are represented only indirectly
through the Lagrange multipliers that are used to modify

20   their objective functions. The single unit DP solution
observes all local constraints, i.e., those that apply to
unit operation (maximum and minimum power limits, minimum
up and down times, ramp rates, etc.). In a single unit DP,
all unit characteristics can be rigorously represented

25   while maintaining a reasonably small state space to ensure
low execution time. The solutions of the unit problems are
coordinated within each plant to meet the plant start-up
constraint by solving the unit problems in order of
solution priority, and constraining start-ups of lower

30   priority units based on the solutions for higher priority
units.

40

The master problem solution is concerned with adjusting the values of the Lagrange multipliers in order to satisfy the coupling constraints. This can be done with an iterative process. At every iteration, all subproblems

5 are solved for a given value of the Lagrange multipliers. Then the multipliers are updated using a subgradient technique in which the change in the value of each multiplier is proportional to the violation of its associated coupling constraint.

10 The computation of the coupling constraints violations is based on a dynamic merit order that is changing from one iteration to another. The dynamic merit order utilizes the information from the dual subproblem (dual cost, MW levels, etc.) to order the units/transactions from the cheapest to

15 the most expensive. Whether a unit is committed or not at a particular time step depends on the unit's position in the dynamic merit order list. Units are committed from the list one-by-one until the coupling constraints are satisfied. If the number of units/transactions is not

20 enough, the value of the violation is computed and the corresponding Lagrange multiplier is updated to prepare for another iteration. The commitment of units from the priority list takes the local constraints such as minimum up and down times into account.

25 It should be noted that this algorithm maximizes the dual problem while maintaining the feasibility of the master problem, in contrast to other Lagrangian approaches that attempt to maximize the dual function then struggle to obtain a feasible primal solution using different types of

30 system dependent heuristics.

Once a commitment solution has been obtained, dispatch levels for the committed units are determined so as to

41

minimize the production costs by dispatching on-line units and committed dispatchable transactions to the most economical MW levels. The dispatch can be formulated and solved in a known way as, for example, an economic dispatch
5   problem based on an equal lambda approach.

The output of the Unit Commitment procedure can be presented to the operator in tabular and graphic displays to assist in the evaluation of the results. Output results include a commitment schedule which specifies 1) the
10   committed units at each time interval of the scheduling period, 2) the generation level of each committed unit, 3) the utilization of interchange transactions, and 4) the interchange power of each transaction.

In addition, the UC procedure can output production
15   costs (per unit, per plant and per total system) including fuel consumption and fuel costs at each time interval and over certain time periods (e.g., a day), start-up costs, and operating and maintenance costs.

The UC procedure also generates, in a known way,
20   transmission line flows (on certain lines in the power system) and reserves (spinning and total standby reserve at each time interval, per unit and per total system).

25   SECURITY CONSTRAINED DYNAMIC OPTIMAL POWER FLOW (SCDOPF)

An exemplary embodiment of a Security Constrained Dynamic Optimal Power Flow (SCDOPF) procedure in accordance with the present invention, will now be described.
30   The SCDOPF procedure of the present invention performs an optimal power flow (OPF) function while recognizing constraints derived from system conditions other than the

42

current operating state. In most cases, this involves considering steady-state, post-contingency operating limits and constraints as part of the pre-contingency optimization. For example, one goal may be to determine

5   the lowest cost power flow solution with the stipulation that all steady-state constraints are within some emergency limits. Another goal may be to determine the set of appropriate preventive and/or corrective actions within the control limits that can be applied within the appropriate

10   time following any one of several specified contingencies.

As described above in connection with FIG. 4, the SCDOPF procedure operates in a closed loop with the Security Analysis (SA) procedure. The SA procedure provides a list of critical contingencies and related

15   constraints and sensitivities. The SCDOPF procedure provides the capability to eliminate (or to reduce, if complete elimination is not possible) constraint violations in the current system state and/or constraint violations in a set of critical contingency states, while at the same

20   time minimizing the total generation price through the redispatch of controls.

The SCDOPF procedure is implemented by adding security constraints to the Dynamic Dispatch problem. These constraints impose additional limits on branch flows for

25   the post-disturbance configurations resulting from a given set of contingencies. This leads to the concept of system security, where the objective is to keep the system in a normal state during the relatively long periods between disturbances and to insure that, on the occurrence of a

30   major disturbance, the system does not depart from a normal state.

43

As described above, the SCDOPF procedure executes as part of the day-ahead and LMP calculation process in the multi-settlement subsystem 120. The SA procedure evaluates a list of contingencies and reports the problems caused by the contingencies. All selected critical contingencies are simulated and resolved using the SCDOPF procedure. After the rescheduling of controls as a result of an iteration of the SCDOPF procedure, the SA procedure performs a new linearization and checking of binding and near binding constraints for each critical contingency.

The SCDOPF procedure simultaneously solves the base case violations and all critical contingency violations. As a result, new unit base points and critical binding constraints for the base case and all contingency cases are formed. As a by-product, locational marginal prices (LMPs) for all control buses are obtained.

The exemplary SCDOPF procedure of the present invention can operate in one of three user-selected solution modes: Preventive Mode, Corrective Mode or Preventive/Corrective Mode.

In Preventive Mode, all control variables are optimized such that no post-contingency adjustments are necessary in order to avoid violation of base case and post-contingency constraints. This is the most secure solution mode, as no operator intervention is required following an anticipated contingency. The consequences of such a solution are a higher pre-contingency objective function (i.e., higher cost of system operation) and a generally more difficult problem to solve. In some cases, the preventive mode solution may not even exist, especially for more severe contingencies under high load system conditions.

44

In Corrective Mode, the control variables are permitted to adjust after the contingency occurs. This is a less secure mode of operation since operator action is required soon after a contingency to reach an acceptable operating state. Such a problem is generally easier to solve, since there are more degrees of freedom in the control adjustments. The corrective mode is solved as a sequence of independent optimization problems, one per contingency.

In Preventive/Corrective Mode, some of the violations for the violated constraints are relieved in the preventive mode, and the rest are relieved in the corrective mode. While this mode presents a significantly larger optimization problem to be solved than the preventive mode, it is more likely than the preventive mode to have a feasible solution. Most of the control variable changes are made post-contingency, and a few control changes are made in the pre-contingency state (base case). The consequences of such a solution are a lower pre-contingency objective function (i.e., lower cost of system operation), and a generally easier (less constrained) problem to solve than in the preventive mode. This should be the preferred solution mode, especially in cases when the preventive mode SCDOPF requires expensive rescheduling of the base case generations. Operating a power system at a much higher cost in order to avoid limit violations in some contingency cases is not desirable and may not be justifiable considering that the problem can be remedied by combining preventive and corrective control actions.

When operating in Preventive Mode, at each main SCDOPF iteration the following optimization problem is formulated and solved:

45

$$\min \sum_{t=1}^{24} \sum_{i=1}^{nc(t)} C_i(x_i(t)) \qquad \text{(EQ. 6)}$$

subject to:

load balance constraints:

$$\sum_{i=1}^{nc(t)} \frac{x_i(t)}{pfbi(t)} = 0 \qquad t = 1,...,24 \qquad \text{(EQ. 7)}$$

limits on control variable changes:

$$a_{li}(t) \le x_i(t) \le a_{ui}(t) \qquad i = 1,...,nc(t); t = 1,...,24 \qquad \text{(EQ. 8)}$$

branch flow limits for the base case and critical contingency cases:

$$\sum_{i=1}^{nc(t)} s_{li}(t) x_i(t) \le c_l(t) \qquad l = 1,...,nbr(t); t = 1,...,24 \qquad \text{(EQ. 9)}$$

reserve constraints:

$$\sum_{i=1}^{nr(t)} (a_{li}(t) - x_i(t)) \ge SR(t) \qquad t = 1,...,24 \qquad \text{(EQ. 10)}$$

and ramp rate limits:

$$r_{di}(t) \le x_i(t+1) - x_i(t) \le r_{ui}(t) \qquad i = 1,...,nc; t = 1,...,24 \qquad \text{(EQ. 11).}$$

The following terms are used in EQs. 6-11:

$x_i(t)$ — the value of control variable (generator or dispatchable load) i at the hour t

$C_i(x_i(t))$ — price of generator or dispatchable load i at the hour t

5    $pfbi(t)$ — loss penalty factor at the bus at which control variable i is connected at the hour t

$a_{li}(t), a_{ui}(t)$ — lower and upper limits on changes of control variable i at the hour t,

10   respectively

$c_l(t)$ — branch flow base case or contingency case violation for branch l at the hour t

$s_{li}(t)$ — the sensitivity of flow in line l with respect to control i at the hour t

15    $r_{di}(t), r_{ui}(t)$ — lower and upper limits on control variable changes between two adjacent hours

$SR(t)$ — the system spinning reserve requirement at the hour t

$nc(t)$ — the number of control variables at the

20   hour t

$nbr(t)$ — the number of violated branch flow constraints for the base case and all the simulated contingency cases at the hour t

$nr(t)$ — number of generators providing spinning

25   reserve at the hour t

The above formulation in the case of the multi-settlement subsystem 120 produces a very large optimization problem. Large optimization problems have typically been

30   solved using special linear programming (LP) techniques.

47

LP techniques, however, are not suitable when the number of constraints and/or the number of controls is very large. To avoid this problem, the known LP implementations have had to severely limit the number of contingencies and

5   related critical constraints that are to be modeled. This approximation presents an unresolved modeling problem for most known SCOPF implementations. By fixing just a small subset of most critical contingencies, there is no guaranty that other contingencies labeled as non-critical will not

10   become critical after a new solution.

        In accordance with the present invention, however, the aforementioned problems associated with LP implementations are avoided by using a method that allows accurate simultaneous modeling of all contingencies for every hour

15   of the day-ahead scheduling period. With the present invention, it is possible to directly involve and model a large number of critical contingencies in the SCDOPF formulation. In an embodiment of the present invention, the resulting optimization problem is solved using a

20   predictor-corrector interior point method, as described in U.S. Patent Application No. 09/273,148, entitled SECURITY CONSTRAINED OPTIMAL POWER FLOW METHOD (Attorney Docket No. 98 P 7523 US 02), filed on even date herewith and incorporated herein by reference, in its entirety.

25   When the SCDOPF procedure is carried out in the preventive/corrective mode, the following formulation is used:

$$\min \sum_{t=1}^{24} \sum_{i=1}^{nc(t)} C_i(x_i(0,t)) \qquad (12)$$

30

48

subject to:

load balance constraints:

$$\sum_{i=1}^{nc(t)} \frac{x_i(k,t)}{pfbi(t)} = 0 \quad , \quad k = 0,...,ncon(t); \quad t = 1,...,24$$

(13)

5

limits on control variable changes:

$$a_{li}(k,t) \le x_i(k,t) \le a_{ui}(k,t) \quad , \quad i = 1,...,nc(t); \quad k = 0,...,ncon(t); \quad t = 1,...,24$$

10 (14)

branch flow limits for the base case and critical
contingency cases:

$$\sum_{i=1}^{nc(t)} s_{li}(t) x_i(0,t) \le c_l(t) \quad , \quad l = 1,..., nbrl \ (t); \quad t = 1,..., 24$$

15

(15)

$$\sum_{i=1}^{nc(t)} s_{li}(t)[x_i(0,t) + x_i(k,t)] \le c_l(t) \quad , \quad l = nbrl \ (t) + 1,..., nbr \ (t); \quad k = 1,..., ncon \ (t); \quad t = 1,...,24$$

(16)

20

reserve constraint:

$$\sum_{i=1}^{nr(t)} (a_{li}(0,t) - x_i(0,t)) \ge SR(t) \quad , \quad t = 1,...,24$$

(17)

25 and ramp rate limits:

49

$$r_{di}(t) \leq x_i(0, t+1) - x_i(0, t) \leq r_{ui}(t) \quad , \quad i = 1, \ldots, nc; \quad t = 1, \ldots, 24$$

(18)

The following terms are used in EQs. 12-18:

$x_i(k,t)$ — the value of control variable (generator or dispatchable load) i at the hour t in mode k ($k=0$ preventive mode control changes, $k=1,\ldots,ncon(t)$ corrective mode control changes)

$C_i(x_i(0,t))$ — price of generator or dispatchable load i at the hour t

$a_{li}(k,t), a_{ui}(k,t)$ — lower and upper limits on changes of control variable i at the hour t for mode k, respectively.

By taking into account the ramping constraints of the generating units (Eq. 11), the SCOPF procedure of the present invention provides a novel security-constrained dynamic OPF (SCDOPF). In an exemplary SCDOPF procedure as an initial step, the system load curve over 24 hours is searched for the time interval (e.g., hour) with the highest load (the "maximum load hour" or MLH). The exemplary SCDOPF procedure described above is then carried out for the maximum load hour, without taking the ramp-up or ramp-down limits of the generating units into account.

The SCDOPF procedure is then carried out for each hour after the MLH, until the end of the day, and each hour before the MLH, until the beginning of the day. In this case, generation unit ramp constraints are taken into

50

account. The processing of hours after the MLH can be done
independently of and in parallel to the processing of hours
preceding the MLH. Such parallel processing can be
advantageously performed by parallel CPU architectures such
5   as that described above.

For purposes of illustration, consider a generation
unit that is scheduled to produce 50 MW during the MLH and
which can vary its power output up or down by 5 MW/min.
Assuming a 10min ramp time in the hour following the MLH and
10   in the hour preceding the MLH, that generator can produce
0 to 100 MW. This range is then used as a constraint by the SCDOPF
procedure of the present invention for the hour preceding
and the hour following the MLH.

It is possible, however, that with the MLH as the
15   initial point, that the SCDOPF problem is unfeasible; i.e.,
cannot be solved. In that case, a different initial point
can be selected by searching for the two contiguous hours
with the largest load change between contiguous hours. Of
those two hours, the hour with the larger load is selected
20   as the starting point. Starting with that hour, the above
procedure is repeated.

LMP CALCULATION
25

The results of the final SCDOPF execution are used in
step 413 to calculate Locational Marginal Prices (LMPs) for
the day-ahead settlement process of FIG. 4. The following
information for each hour of the day-ahead scheduling
30   horizon is available:

- The marginal prices of generation $\lambda_i, i \in G$

51

- The marginal price of generation at the reference
bus λ

- The marginal cost of those transmission constraints
that are active $\pi_i, i \in L$

5

In addition, the EMS Network Sensitivity (NS) function
provides delivery factors ($d_{k,r}$) that approximately model the
effects of transmission losses in delivering power from a
specific bus k on the system to the reference bus r and
10   sensitivities of the flows in constrained transmission
lines with respect to the load at load bus $s_{k,i}$.

Based on this information, the LMPs are calculated for
each load bus. The marginal price of load at the load bus
k is calculated as:

15

$$\lambda_k = \lambda \cdot d_{k,r} + \sum_{i \in L} \pi_i s_{k,i}$$

(EQ. 19)

It is possible to calculate the LMPs, with or without
marginal losses. Based on data prepared by the ISO the
20   marginal prices at load buses are appropriately aggregated
and corresponding zonal prices are calculated.

The day-ahead LMP Calculation function supplies the
calculated LMPs to the Scheduling Database 130 for posting
purposes and to the Accounting Database 190 for Billing and
25   Settlement activities. Generators selected by the UC
procedure receive the LMPs as calculated for the
generators' points of injection for the level of generation
required to serve the day-ahead load bids. The loads will
pay the zonal LMPs associated with their zone of extraction

52

for the energy that they have bid into the day-ahead market.

5   HOUR-AHEAD SCHEDULING

From the time the day-ahead schedule of operation is completed and communicated to the Market Participants 50, up to the actual operating hour, a Market Participant may

10   inform the energy market system 100 of changes to the participant's scheduled commitments. These participant adjustments might be in response to changed conditions affecting generation or loads or to changed expectations about the direction of prices between the day-ahead market

15   and the real-time market. These adjustments are treated as deviations from the day-ahead schedules. The participants would still be financially committed to the day-ahead schedules at the day-ahead prices. Market Participants could cover their day-ahead schedules (forward sales)

20   either by operating according to the day-ahead schedules or by settling any deviations from the day-ahead schedules at the real-time prices determined from the actual dispatch. During this timeframe, additional generation may be scheduled with an hour-ahead scheduling procedure in

25   accordance with the present invention. The commitment of additional units in the hour-ahead market is based on minimization of start-up and no-load bids.
The following adjustments may be made on an hour-to-hour basis prior to the operating hour:

30   ● A Market Participant may self-schedule any of its resource increments, including hydro power resources not previously designated as Self-

53

Scheduled Resources and not selected as a Pool-Scheduled Resources.

- A Market Participant may request the scheduling of a new bilateral transaction that uses non-firm transmission service (not paying congestion charges).

- A Market Participant may remove from service a resource increment, including a hydro power resource that it had previously designated as a Self-Scheduled Resource, provided that the market system has the option to schedule energy from such resource increment at the price offered in the scheduling process, with no obligation to pay any start-up fee.

- An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase by notifying the energy market system of the adjustment in deliveries later that one hour prior to the hour in which the adjustment is to take effect.

- Generation that was scheduled in the day-ahead market could lower its bid prices.

- Transmission customers not scheduled in the day-ahead market can submit bilateral transaction schedules.

- External bilateral transactions may revise their schedules up to one hour before the operating hour. Such deviations from the day-ahead schedule will pay congestion charges based on the real-time prices.

54

o Generators can inform the market system of the
   bilateral or self-scheduling of generation
   segments not in the day-ahead schedule. Loads
   and transmission customers scheduled day ahead
5 could submit adjustments to their existing
   schedules.

o Flexible generators, loads and transmission
   customers not scheduled in the day-ahead
   scheduling process to either operate or provide
10 reserves could submit bids to provide
   additional generation or load, and could submit
   additional transmission schedules with
   incremental and decremental bids. These bid
   prices could be either higher or lower than
15 those submitted for these same generation
   resources or loads in the day-ahead scheduling
   process.

o Flexible generators, loads and transmission-
   only customers scheduled in the day-ahead
20 scheduling process to either operate or provide
   reserves can lower their bid prices (relative
   to those submitted in the day-ahead settlement)
   but can not raise them. Quantity changes would
   be allowed (i.e., withdrawal of units due to
25 forced outages) but would not affect the
   financial commitments determined by the day-
   ahead schedule.

o Inflexible generators, loads and transmission
   customers could submit schedules for additional
30 generation, load and bilateral transactions.

55

In accordance with the present invention, hour-ahead
rescheduling, without need for commitment of additional
units, is performed by execution of the SCDOPF procedure
and the SA-SCDOPF loop. The SCDOPF procedure is run to

5   obtain a basic optimal solution. Following this, the SA-
SCDOPF loop is performed to obtain an optimal solution with
no violations in the base case and in the contingency cases
set forth in the contingency list.

      If for the hour-ahead rescheduling it is necessary to

10   commit additional units, the MUC procedure (commitment with
start-up and no load cost) performs the commitment of the
additional units. The total capacity of units that must be
committed in the MUC run, and the available set of units
that are candidates for commitment are in as inputs to the

15   MUC procedure. Following this, the SCDOPF procedure and
the SA-SCDOPF loop are run to obtain the final optimal
solution.

      The resulting schedules are transmitted to the
Scheduling Database 130 for posting purposes. The results

20   are also communicated to the EMS 15 for next hour
operations. The results of the hour-ahead scheduling
process are supplied to the Accounting Database 190, such
as for audit purposes. These are not used for billing and
settlement calculations. The real-time settlements are

25   calculated based on actual real-time information received
from the EMS system and from the real-time LMP calculation
function 16.

      The hour-ahead scheduling process can use the same
graphical user interface provided for the day-ahead

30   scheduling process. A system operator can inspect hour-
ahead scheduling results prior to transmittal to the
scheduling database, to the Accounting database, or to the

<div align="center">56</div>

EMS system and to modify inputs and rerun the scheduling function.

5   FTR AUCTION SUBSYSTEM

        As mentioned above, in addition to providing a multi-
settlement subsystem 120, the exemplary embodiment of the
energy market system 100 of the present invention also
10   includes a Fixed Transmission Right (FTR) Auction subsystem
160, which will now be described in greater detail.
        An FTR is a financial instrument that can hedge its
owner against congestion charges incurred on a specific
transmission path. An FTR provides its owner with the
15   right to receive congestion credits, for a specified amount
of power, when the power system is congested. The revenues
associated with congestion charges are redistributed to the
owners of FTRs. This essentially provides the owner of an
FTR with the right to transfer a specific amount of power
20   over a transmission path, for a specific price, regardless
of congestion charges that might otherwise apply.
        The FTR Auction subsystem 160 provides for the
purchase and sale of FTRs in a centralized auction. Market
participants may submit bids for the purchase of FTRs in
25   the auction. They may also offer FTRs for sale in the
auction. The auction system will maximize the revenues
collected by the ISO from the FTRs while maintaining the
ability of the transmission system to simultaneously
support the awarded FTRs.
30   Each FTR is characterized by the time period over
which the FTR is valid and the busses to which the FTR
applies. An FTR may be between a single bus and a single

                                57

bus, a single bus and multiple busses, multiple busses and a single bus, or multiple busses and multiple busses. The busses used in the designation of an FTR must be busses where Locational Marginal Prices (LMPs) are calculated. An

5   FTR may be designated with an injection location inside the ISO's control area and a withdrawal location outside of the control area, with an injection location outside of the control area and a withdrawal location inside of the control area, or with both the injection and withdrawal

10   locations inside of the control area.

There are several different ways to acquire FTRs. It is the method of acquisition that differentiates FTRs. FTRs can be acquired as follows:

15   o   Network Integration Service FTRs - these are FTRs that are awarded to network service transmission customers.

o   Firm Point-to-Point Service FTRs - these are FTRs that are awarded to firm point-to-point

20   transmission customers. They have time periods based on the duration of the reserved transmission service.

o   Secondary Market - the holders of Firm Transmission service may sell the FTRs to Market

25   Participants in a secondary market.

o   FTR Auction - Market Participants may buy and sell FTRs through an auction, such as that provided by the auction subsystem of the present invention.

30

FTRs acquired by one of the first three methods are referred to as pre-allocated FTRs. These will form a base

58

level of FTRs during the simultaneous feasibility procedure of the FTR Auction, described below.

There are essentially three time periods associated with the FTR Auction process. The first is the advance information time period, during which the expected FTR capacity that will be available during the auction will be determined and publicly posted (e.g., on the Internet via the MUI). Historical information related to congestion prices and limiting conditions on the energy system preferably are also posted.

The second time period is the deadline by which Market Participants art to submit auction information. By day N the market participants should submit bids for FTRs they wish to purchase in the auction or offers for FTRs they wish to sell. In accordance with the FTR auction process, to bid on an FTR for purchase, a potential purchaser specifies the power injection and withdrawal locations, the desired capacity and the bid price. When offering an FTR for sale, the potential seller specifies the power injection and withdrawal locations, the FTR's capacity and a reservation bid, i.e., the minimum price the seller wishes to receive.

The FTR auction will then be run to determine which set of bids to award, along with which set of FTRs to sell. By day N+1 the winning set of bids (both sale and purchase) are posted along with the market-clearing prices for the FTRs. The winning bidders will pay the market-clearing price for the FTRs they acquire in the auction while the FTR sellers will be paid the market-clearing price for FTRs they surrender.

FTR auctions can be held periodically, such as once a month. Separate FTR auctions can be performed for peak conditions and off-peak conditions.

The FTR auction system of the present invention also
5   provides a mechanism for the short-term reconfiguration of FTRs. A Market Participant may request, and possibly be awarded, an FTR that is different from any of the FTRs being sold into the auction by sellers. This provides a Market Participant with the opportunity to purchase FTRs
10   that would not otherwise be available through bilateral transactions in a secondary market.

FIG. 1 includes an overview of the FTR auction subsystem 160 of the present invention. The FTR auction subsystem 160 comprises an FTR Auction Database 170 and a
15   processing block 180 which comprises a Case Setup function 181, a Simultaneous Feasibility Test (SFT) function 182, and an FTR Auction Post-Processing function 183. The FTR auction subsystem 160 also interacts with the Application Database (ADB) ISO and the Accounting Database 190 and
20   interfaces with the Market User Interface 110 and the EMS 15.

The Case Setup function 181 assembles the case that will be analyzed by the Simultaneous Feasibility Test (SFT) function 182. The Case Setup function 181 is preferably
25   executed separately for peak and off-peak conditions.

FIG. 5 is a flow chart which illustrates the steps performed in carrying out the case setup function 181. The first step 801 of the case setup function 181 is to collect information for performing the SFT 182.

30   The FTR auction database 170 is the main database for the setup of the FTR auction. It can be implemented, for example, as an Oracle database. The Market User Interface

60

110 stores market participant data and bid information from the market participants 50 in the FTR auction database 170. In addition, data from various subsystems of the energy system to support the FTR Auction is collected in the FTR

5   auction database 170.

The data stored in the FTR auction database 170 includes:

- outages that are active for the relevant period (e.g., month);

10   - peak load conditions;

- off-peak load conditions;

- the pre-allocated FTR information;

- the FTR bid information;

- the MW limits to use for branch ratings;

15   - the transfer interface limits;

- the list of contingencies to analyze;

- the information describing zonal and hub aggregate price definitions; and

- information about uncompensated parallel flows.

20   In addition to the aforementioned data stored in the FTR auction database 170, the FTR auction subsystem also accesses the ADB database which contains a breaker-oriented network model of the power system.

Once the above-described data has been set-up,

25   topology processing is performed at step 803 to include the effect of outaged equipment. Load scheduling (step 805) and generation scheduling (step 807) are then performed for loads and generation units external to the ISO's control area. The load and generation scheduling steps 805 and 807

30   serve to set-up representative conditions for neighboring electrical systems. The bus injections external to the

61

control area are thus determined. The bus injections
internal to the control area are determined based on the
pre-allocated FTR information.

Once the case setup function 181 has been performed,
execution proceeds to the Simultaneous Feasibility Test
(SFT) 182, which will now be described with reference to
FIG. 6. The SFT determines how to maximize the revenue
obtained from the auction while insuring that the FTRs that
are awarded do not exceed the capacity of the transmission
system.

At step 901, an initial DC power flow solution is
performed based on the loading defined for the external
portion of the system with the loading for the internal
portion of the system based on the pre-allocated FTR
information. The Model Update (MU) and Dispatcher Power
Flow (DPF) functions described above in connection with the
multi-settlement subsystem 120 are used to obtain the
initial DC power flow solution. Since only DC network
solutions are being performed in the SFT, it is not
necessary to execute the Regulating Equipment Scheduler
component of the model update function. Furthermore, with
respect to the DPF, the loading level for the internal
portion of the system will correspond to the pre-allocated
FTRs. That is, the injections and withdrawals will
correspond to the FTRs that are defined, not to the
generators and loads of the system. This solution will
serve as the starting point to the optimization process.

Following the initial solution provided in step 901,
an optimization is performed at step 903 which considers
base case constraints only. The optimization is performed
using a "static" subset of the SCDOPF procedure described
above. In this case, referred to as the SCOPF procedure,

62

the optimization problem being solved is different than the
one being solved for the multi-settlement subsystem 120.
In this case, the objective function to be maximized is the
revenue received by the ISO from the FTRs. Furthermore,

5   the equality constraints include the DC version of the
static load flow equations and additional equations that
associate the FTR variables with injections and withdrawals
at their injection and withdrawal locations. The
inequality constraints include the specified capacities of

10   the FTRs being bid (i.e., the limits on the control
variables), the limits on the MW flow on branches for the
base case network, the limits on the transfer interface MW
flows in the base case, and the limits on the MW flow of
branches under contingency conditions.

15   The SCOPF problem that is being solved during the SFT
procedure of the FTR auction uses modeling similar to that
used for the evaluation of potential transactions during a
typical OPF cost optimization solution. At each of the
main SCOPF iterations the following problem is formulated

20   and solved:

maximize: $\displaystyle\sum_{i=1}^{nc} C_i X_i$ (EQ. 20)

subject to:

25

limits on control variable changes:

$$a_{ti} \leq x_i \leq a_{ui} \qquad \text{(EQ. 21)}$$

63

and transfer interface and branch flow limits for the base case and contingency cases:

$$\sum_{i=1}^{nc} s_{\ell i} x_i \leq c_\ell \ , \ \ell = 1,...,nbr \qquad \text{(EQ. 22)}$$

5

The variables used in EQs. 20-22 are defined as follows:

x_i — the value of control variable i, namely the MW value of FTR_i.

10 c_i — the price of control variable i, this is either the bid price or reservation price of FTR_i.

$s_{\ell i}$ — the sensitivity of flow in line l with respect to control i.

15 c_l — branch flow base case or contingency case limit.

$a_{\ell i}$ — the lower limit for control variable i. For a bid to purchase an FTR this is zero. For a bid to sell an FTR this is the

20 negative of the capacity offered for sale.

a_{ui} — the upper limit for control variable i. For a bid to purchase an FTR this is the capacity being requested. For a bid to sell an FTR this is zero.

25 nc — the number of control variables (i.e., the number of FTRs)

nbr — the number of violated transfer interface limits, base cases branch flow limits, and contingency case branch flow limits.

64

If it is determined at step 905 that the SCOPF
procedure does not yield a feasible solution, the operator
is informed in step 907. If the SCOPF procedure does yield
a feasible solution, execution proceeds to step 909 in
5   which the Security Analysis (SA) procedure is used to
analyze the impact of contingencies on this solution.

The Security Analysis (SA) procedure is substantially
the same as described above in connection with the multi-
settlement subsystem 120, with several simplifications. In
10   this case, the power flow solution that is performed is a
DC solution, no voltages are calculated or checked for
violations, and the contingency screening is real power
only.

In the SCOPF portion of the SFT procedure, the control
15   variables are the MW value of the FTRs. These FTR MW
values are mapped to bus injections during the SA
processing using the matrix W described below. The
modified problem to be solved in the SA procedure is:

20   $\Delta P = B' \Delta \theta + Wx$ (EQ. 23)

for the base case, and:

$\Delta P_c = [B'+\Delta B'] \Delta \theta_c + Wx$ (EQ. 24)

25

for each contingency case.

The terms used in EQs. 23 and 24 are defined as follows:

30   X_i – the value of control variable i,
                              namely the MW value of FTR_i

65

	ΔP	- the vector of bus active power mismatches for the base case
	B'	- the active power sub matrix from the Fast Decoupled Power Flow formulation
5		for the base case network
	$\Delta\theta$	- the vector of bus voltage angle corrections for the base case
	W	- An nbs by nc matrix that maps the MWs associated with an FTR to its injection
10		and withdrawal busses. For example, if FTR_i (or X_i) has bus j as its only
		injection bus and bus k as its only withdrawal location, column i will be
		all zeroes except for +1 in row j and
15		-1 in row k. For FTRs that have multiple injection busses and/or
		multiple withdrawal busses, each bus would have a participation factor that
		indicates the portion of the FTR
20		associated with that bus. All the injection participation factors would
		sum to +1 and all the withdrawal participation factors would sum to -1.
	nc	- the number of control variables
25		(i.e., number of FTRs)
	nbs	- the number of busses in the system
	ΔP_C	- the vector of bus active power mismatches for a contingency case
	$\Delta\theta_C$	- the vector of bus voltage angles for
30		the contingency case

66

$$\Delta B' \qquad \text{- the matrix of changes to B' matrix}$$
$$\text{that corresponds to that contingency}$$

Each of the cases that is solved is checked for

5   violations.   The base case is checked for transfer
interface limit violations and branch flow limit
violations.   The contingency cases are checked for branch
flow limit violations.   For every violation that is
detected, the SA procedure will calculate the sensitivity

10 of the flow on the violated branch to the control
variables, i.e., to the FTRs.   These sensitivities are
passed to the SCOPF procedure.   The SCOPF procedure then
reschedules the control to alleviate the violations in an
optimal manner.

15   If it is determined at step 911 that any contingencies
result in new violations, these will be passed back to the
SCOPF optimization procedure 903 as constraints which are
to be enforced.   This process will be repeated until all
violations are handled.

20   Once all violations have been handled and it is
determined at step 911 that there are no more violations,
execution proceeds to step 913 in which the pricing of FTRs
is carried out.

The pricing of FTRs is based on their market-clearing

25 price.   All participants pay the market clearing price for
the FTRs they buy in the auction, or receive the market
clearing price for the FTRs they sell into the auction.
The FTR auction process leads to nodal prices for FTRs
(i.e., this would be the price for an FTR from a particular

30 bus to the reference bus).   One consequence of this is that

it is possible to see the market-clearing price for FTRs
between locations that were not bid into the auction.

The calculation of the nodal prices starts from the
set of binding constraints during the optimization. Each
binding constraint has a marginal cost associated with it.
This is how much the objective function would change if the
limit on the constraint could be relaxed slightly (assuming
all other constraints stay binding). If the injection at a
bus is changed it will result in a change in the value of a
binding constraint. Multiplying the marginal cost of the
binding constraint by the impact on it due to an injection
change yields the change in the objective function due to
the change in the injection. Adding these terms together
for all the binding constraints yields the nodal price for
the bus. This calculation is performed for each bus of
interest. This procedure is similar to the methodology
that is used for the real-time LMP price calculation.

Once the SFT 182 has been completed, execution
proceeds to the FTR Auction Post-Processing procedure 183.
The Post-Processing procedure 183 transfers the results of
the auction to the FTR database 170 and to the Accounting
database 190. The information that is transferred to the
FTR database 170 is used by the Market User Interface 110
to post auction results on the Web for Market Participants
50 to view.

Separating the post-processing function 183 from the
other auction functions provides auction administrators the
opportunity to review results before posting them. The
following results are transferred by the post-processing
function to the FTR database 170: 1) FTRs awarded in the
auction; 2) FTRs sold in the auction; 3) the nodal prices
for FTRs (or the price for an FTR from a bus to the

68

reference bus); and 4) information about which constraints were binding during the auction.

This information is also transferred to the Accounting database 190 where it can be accessed by the accounting and billing subsystem 17 of the energy system. In addition, the FTR Auction Post-Processing function 183 stores additional data in the Accounting database 190 as necessary to support data archiving and auditing requirements. An auction administrator can retrieve data from this location and transfer it for data warehousing purposes. The accounting database 190 can be implemented using an Oracle database.

For administrative users, Oracle Forms and Application Data Viewer (ADV) displays are also available to aid in operating the auction subsystem 160.

69